MEMORANDUM

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FROM: Amanda Singleton, and Graham Gibson, ERG

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SUBJECT: Revised Methodology for Estimating Cost and Emissions Impacts for Industrial, Commercial, Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants – Major Source

1.0 INTRODUCTION

The purpose of this memorandum is to discuss the revised methodology used to estimate the costs, emission reductions, and secondary impacts from industrial, commercial, and institutional boilers at major sources of hazardous air pollutants (HAP). These impacts were calculated for existing units and new units projected to be operational by the year 2013, three years after the rule is expected to be promulgated. The results of the impacts analysis are presented for both the regulatory option contained in the promulgated rule and a more stringent regulatory option. The development of the maximum achievable control technology (MACT) floor level of control, projection of new units, and a detailed description of the cost equations used to estimate costs for various control technologies is presented in other memoranda.[1,2,3] This memorandum is organized as follows:

1.0 Introduction
2.0 Overview of Regulatory Options
3.0 Estimating Cost Impacts
4.0 Methodology for Estimating Emission Reductions
5.0 Methodology for Estimating Secondary Impacts
6.0 References

2.0 OVERVIEW OF REGULATORY OPTIONS

Two control options were considered for existing boilers and process heaters at major sources of HAP. A description of the two options is included in this section.

2.1 Existing Units

- The recommended option is the option presented in the preamble and final rule. In this option, small boilers and process heaters (less than 10 mmBtu per her), limited use boilers and process heaters (operating less than 876 hours per year), and boilers burning natural gas, refinery gas, or other on-spec gaseous fuels are subject to work practice standards in lieu of numeric emission limitations. The work practice standard small and limited use units is a biennial tune-up and the work practice standard for larger natural gas, refinery gas, or other on-spec gaseous fuels is an annual boiler tune-up. Boilers not meeting one of those criteria are subject to numeric emission limitations for Hg, PM, HCl, CO, and TEQ dioxins/furans. Boilers combusting at least 10 percent solid fuels, either coal, other fossil solids or biomass are grouped into a single solid fuel subcategory and are subject to identical emission limitations for the fuel-based pollutants Hg, PM, and HCl. For combustion-based pollutants CO, and TEQ dioxins/furans separate combustor design subcategories are considered for coal/fossil solids and biomass. Units designed to burn liquid fuels, units located in non-continental States and United States Territories designed to burn liquid fuels, and units burning off-spec gaseous fuels (other process gases) each have a single subcategory for both fuel and combustor-based HAP.

- The alternative option is identical to the recommended option except that boilers combusting at least 10 percent solid fuels are subject to separate numeric limits depending on the class of solid fuel combusted. Units burning coal or other fossil solids have separate numeric emission limitations from units burning biomass or other bio-based solids for Hg, PM, and HCl.

2.2 New Units

The same two control options for existing units were used for new units. However, since it is projected that no new boilers combusting solid fuel (biomass or coal) will be constructed by 2013, the results of the cost and emission impacts analyses for both options are identical.

3.0 ESTIMATING COST IMPACTS

For each option, the cost impacts analysis compares the baseline emissions for each unit to the corresponding MACT floor emission limit for the unit's subcategory. A control device was applied to the unit if its baseline emissions exceeded their applicable MACT floor emission limit.

A comparison of the overall capital and annualized costs of the recommended option are presented in Table 1. The detailed equations used to estimate the control, testing, monitoring, and work practice costs are discussed in another memorandum.[2] The following logic was used to apply control, testing, and monitoring costs to each boiler or process heater:

3.1 Recommended Option

The recommended option represents an option with a consolidated subcategory for fuel-based HAP from solid fuel units, where every unit must meet numerical emission limits and demonstrate compliance with performance stack testing, monitoring, and fuel analysis with a few exceptions. Units in the gas 1 subcategory, small units (less than 10 mmBtu/hr), and limited use units (less than 876 operating hours per year), qualify for work practices under Section 112(h) of the CAA and work practices consisting of an annual or biennial tune-up replace the traditional compliance demonstrations associated with numeric emission limits.

Control Cost Impacts

Mercury Control

- Fabric filters — a new fabric filter installation was expected to achieve most of the Hg emission limits in the final rule. Where baseline Hg emissions were found to be greater than the MACT floor, the cost of a fabric filter was estimated for an individual boiler or process heater, unless the unit already had a fabric filter installed. A new fabric filter was estimated to be installed at 454 existing boilers and process heaters. This does not include the fabric filters installed in combination with dry injection to achieve HCl controls that are discussed below.
- Activated carbon injection (ACI) — In the case of a unit with a fabric filter emitting Hg above the MACT floor emission limit, the incremental Hg removal efficiency required to meet the MACT floor was calculated, and then the costs to install activated carbon injection (ACI) technology on the boiler were estimated. Incremental ACI equipment was installed for 108 existing boilers and process heaters.
- Wet scrubbers—one of the technologies selected for the cost analysis to reduce emissions of hydrogen chloride (HCl)—is also capable of achieving modest reductions in Hg. Literature suggests that these scrubbers can achieve a 10-percent reduction in Hg

emissions. If a scrubber was being installed for HCl, and baseline Hg emissions were within 10 percent of the MACT floor, the wet scrubber was expected to achieve this level of emission reduction without installing a fabric filter.

Particulate Matter Control

- When baseline particulate (PM) emissions exceeded the MACT floor, the cost of an ESP was estimated, unless a fabric filter had already been included in the cost analysis for Hg reduction. ESP technology was estimated to be installed at 10 existing boilers and process heaters.
- Wet scrubbers are also capable of achieving a modest reduction in PM. Literature suggests that these scrubbers can achieve an 85-percent reduction in PM emissions. If a scrubber was being installed for HCl, and baseline PM emissions were within 85 percent of the MACT floor for PM, the wet scrubber was expected to achieve this level of emission reduction without installing an ESP.

Hydrogen Chloride Control

- When HCl baseline emissions were greater than the MACT floor, the cost of adding a packed bed scrubber, increasing the sorbent rate on an existing scrubber, or installing a combination fabric filter and dry injection (DIFF) system was estimated. Scrubbers and DIFF were estimated to be able to attain similar levels of hydrogen chloride control. Based on input received during the public comment period, many wood product facilities are not permitted to discharge wastewater, thereby restricting the type of controls needed to reduce emissions of HCl and other acid gases. For this analysis, facilities in NAICS codes 321 (wood products manufacturing) and 322 (paper manufacturing) were assumed to not be able to install a packed scrubber due to the regulation of wastewater discharge from those industries. For the remaining units requiring control device installation for hydrogen chloride reduction, the less expensive control option between a packed scrubber and DIFF was assumed to be the control installed. If the boiler already reported having a scrubber installed, a DIFF was not the selected control technology, and the baseline emissions still exceeded the floor, the incremental required HCl removal efficiency was calculated and the then the cost to increase the sorbent injection rate in the scrubber was estimated in the cost analysis. Wet scrubbers were estimated to be necessary to control HCl emissions at 774 existing boilers and process heaters. DIFF was identified to be necessary to control HCl emissions at 136 existing boilers and process heaters. Incremental sorbent injection was identified to be necessary to control HCl emissions at 7 existing boilers and process heaters.

- Since the fabric filter portion of a DIFF will achieve reductions in both HCl and Hg, the analysis first checked for whether a DIFF was necessary to achieve HCl reductions, and if so, this DIFF was assumed to achieve the MACT floor limits for both HCl and Hg. If a DIFF was not needed for HCl control, but a fabric filter was needed for mercury control, the costs of a fabric filter were estimated.

Dioxin/Furan Control

The final rule requires all units that measure dioxin data below the method detection level to report that congener as zero. Based on the reported dioxin/furan data and associated detection levels available at the time of the final rule, most units will fall below the MACT floor levels if the non-detect congeners are treated as zero, For coal, 17 of the 27 tests would meet the existing limits, 17 of the 22 tests for biomass would meet the existing limits, and all of the liquid and process gas tests would meet the existing limits. Given these results and the fact that some units are installing ACI for mercury control, which is expected to have a co-benefit of reducing dioxin/furan emissions, the cost analysis does not estimate any control costs for achieving the dioxin/furan emission limits.

Carbon Monoxide and Organic HAP Control

- Organic HAP and carbon monoxide can be controlled by either improving the combustion efficiency of the unit, or installing an oxidation catalyst on the exhaust of a combustion unit. The control strategy necessary to meet the MACT floor emission limit will vary depending on the magnitude between the baseline emissions and the CO MACT floor. A step function was used to delineate what type of control strategy should be analyzed in the cost impacts analysis:
    - A boiler tune-up was estimated in the cost impacts analysis if the unit's CO baseline emissions were less than or equal to 1.5 times the applicable numeric CO

emission limit. Some commenters, including facilities and boiler and burner vendors, suggested that the concrete threshold of 400 ppm used in the CO control cost analysis in the proposal was an inappropriate cutoff for determining whether or not a tune-up could achieve the CO emission limits for certain boiler types. Many of these commenters added that significant changes in CO could not be made without a tradeoff in increased NOX emissions. Based on data in the record as well as public comment submittals, CO emissions can fluctuate widely due to operating loads and conditions. Further, most units in the database do not report dedicated combustion controls or CO oxidation catalysts installed to reduce CO emissions. Instead of using a concrete threshold of 400 ppm in final analysis, we estimated that tune-ups could achieve a percent reduction from the unit's baseline emissions. To determine an appropriate threshold level that tune-ups could achieve the limits to demonstrate annual compliance with the CO stack test in the final rule, we looked at best performing units for CO that reported paired CO CEMS emissions and boiler load data. Best performing CO units in the coal/fossil solid stoker, biomass/bio-based solid dutch oven/suspension burner and hybrid suspension grate subcategories biomass had data available. None of these units with paired CO and load data reported having any add-on dedicated CO controls or combustion controls installed on the unit. The WVDupontWashingtonWorks P05 unit reported a wide range of CO emissions at loads greater than 75 percent of its design capacity, the maximum CO value was over 9 times greater than the minimum CO value at the unit. For biomass units, the range is even more pronounced, at TXDibollTemple-Inland PB-44, the maximum CO value at loads greater than 50 percent was nearly 900 times higher than the minimum CO value, and at hybrid suspension grate burners, FLUSSugar, Boiler 8, the maximum CO value was over 1,700 times higher than the minimum CO value. Despite these large ranges, the CO stack test values of these units were all meeting the floor values during their emission stack tests. We settled on a modest threshold condition of assuming that a tune-up would meet the limit if the floor value was within 150% of the baseline emissions. Based on data provided by best performing units, it is reasonable and a conservative estimate that this level of control can be achieved without capital installations.

- If the unit's baseline CO emissions were greater than 1.5 times but less than or equal to 2.5 times the applicable numeric CO emission limit, the cost of a replacement low-NOx burner was estimated to achieve the MACT floor emission limits. Since stokers, fuel cells, or fluidized bed unit do not have replaceable burners, a linkageless boiler management system (LBMS) was the technology estimated to achieve the MACT floor when baseline CO emissions exceeded the floor in lieu of replacement low-NOx burners. A threshold of 2.5 is still less than the reported findings from best performing boilers in the coal and biomass subcategories that demonstrate wide fluctuations in CO emissions without any added CO controls, as discussed above. However, since we do not have similar data available for the liquid and process gas subcategories, we opted to select a conservatively low threshold to address some concerns received from public comments about underestimating the costs of CO control.
- Finally, if the baseline CO emissions were greater than 2.5 times the applicable CO emission limit, the cost impacts analysis estimated that a CO oxidation catalyst would be required to meet MACT floor limits.

Work Practice Costs

- All small boilers (less than 10 mmBtu per hour), limited use boilers (less than 876 hours of operation per year), are required to conduct a biennial boiler tune-up. All large boilers burning natural gas, refinery gas, or other on-spec gaseous fuels are required to conduct an annual tune-up. The cost to conduct an annual tune-up is based on the cost estimate provided in a report by the Industrial Extension Service[16]. This report indicated that the initial set-up for boiler tune-up was $3,000 to $7,000 per boiler; thereafter, annual tuning costs $1,000 per boiler. An average of $5,000 per boiler initial set-up costs was annualized over 5 years at a 7 percent rate, and added to the subsequent year tune-up costs. The resultant annualized cost for an annual tune-up is $2,875 per boiler, as shown in Equation 1.

$$\text{Annual Tune-up Cost (\$2008)} = \{[C_{\$2004} * (X_{2008} / X_{2004}) * i * (1+i)^y] / [(1+i)^y - 1)]\} + [Z_{\$2004} * (X_{2008} / X_{2004})] = \$2{,}875 \qquad \textbf{(Equation 1)}$$

Where:

$C_{\$2004}$ = Average set-up cost, $5,000 (from 2004)

X_{2008} = 2008 cost index, 575.4
X_{2004} = 2004 cost index, 442.2
i = interest rate, 7%
y = length of annuity, 5 years
$Z_{\$2004}$ = annual tuning cost, $1,000 (from 2004)

Biennial tune-up costs would provide some cost savings, although the costs of the initial tune-up set-up must be factored into both of the work practice frequencies, so this analysis used a single tune-up cost, which is based on an annual frequency. The annualized cost for a biennial tune-up is $2,228 per boiler, as shown in Equation 2.

$$\text{Biennial Tune-up Cost (\$2008)} = \{[C_{\$2004} * (X_{2008}/X_{2004}) * i * (1+i)^y] / [(1+i)^y - 1)]\} + [(Z_{\$2004} / 2) * (X_{2008}/X_{2004})] = \$2{,}228 \qquad \textbf{(Equation 2)}$$

Where:
$C_{\$2004}$ = Average set-up cost, $5,000 (from 2004)
X_{2008} = 2008 cost index, 575.4
X_{2004} = 2004 cost index, 442.2
i = interest rate, 7%
y = length of annuity, 5 years
$Z_{\$2004}$ = annual tuning cost, $1,000 (from 2004)

A total of 12,266 boilers and process heaters meet one of the above criteria and are subject to a tune-up work practice in lieu of add-on controls.

- All facilities are expected to conduct a one-time energy audit. An annual cost of $854 per audit was used for commercial facilities and $18,292 per audit was used for industrial facilities, and these costs are the same as the estimates included in the proposal. Although some commenters indicated EPA underestimated the costs of the assessment, in the final rule EPA has reduced the scope of the assessment in the final rule to an assessment that does not exceed one to three days in length for units consuming less than 1 trillion Btu/year of energy. For larger units, the audit is reduced in scope to assess for at least 20 percent of the energy output of the boiler system. As discussed in the memorandum for Estimating Control Costs from Major Source Boilers and Process Heaters, the cost of an energy audit ranges from $75,000 for industrial-scale energy audits to between $2,000 and $5,000 per energy audit for institutional and commercial-scale audits.[2] This larget estimate is based on costs presented to the 2009 Boiler Small Business Regulatory Flexibility Act panel by an affected small entity, Port Townsend Paper Company. The cost of each type of audit was annualized over 5 years at 7 percent to obtain an annualized cost estimate. For the cost impacts analysis, 1,639 facilities are expected to conduct an audit, 197 facilities are commercial or institutional and 1,442 facilities are industrial.

Testing and Monitoring Cost Impacts

Testing and monitoring requirements varied depending on the equipment installed on the unit to control emissions, the design capacity of the unit, and the fuel category the unit was assigned to.

Testing Costs

All boilers and process heaters designed to burn solid and gaseous fuels were expected to conduct an annual compliance test for PM, HCl, Hg, D/F, and CO. The cost to conduct stack tests for these five pollutants was estimated to be $44,000 per year for boilers combusting solid or other gaseous fuels. Based on comments received about testing under worst-case conditions, many solid fuel boilers which fire multiple fuel streams or types of fuel are expected to conduct repeated testing for mercury and HCl at a cost of $18,000 per year.

Boilers and process heaters designed to burn liquid fuels were expected to conduct an annual compliance test for PM, D/F, and CO. In lieu of a stack test boilers designed to burn liquid fuels were expected to conduct fuel analysis, or report fuel analyses received from a fuel supplier for chlorine and Hg. Conducting stack tests for PM, D/F, and CO and fuel analysis for chlorine and Hg was estimated to be $16,000 per year. Although other fuels are eligible to comply with the promulgated rule through fuel analysis in lieu of stack testing, this cost estimate conservatively assumed that only units designed to fire liquid fuels would use this compliance alternative. The methods and data sources used to estimate testing and monitoring costs are discussed in other memoranda.[2]

The final rule includes a provision for gaseous fuels other than natural gas and refinery gas to demonstrate that they meet the specifications outlined in the rule for mercury and hydrogen sulfide. We reviewed the database for facilities that had boilers with heat input capacities of at least 10 mmBtu/hr that are firing gaseous fuels other than natural gas or refinery gas, and we estimated that these 45 facilities would need to conduct monthly fuel analysis, at a cost of $600 per month, or $7200 per year. The methods and costs associated with demonstrating that the gas meets the specifications for mercury and hydrogen sulfide are discussed in another memorandum.[4] Because the fuel spec can be conducted upstream of the combustion equipment, EPA determined that one specification per month, per facility, would be the likely compliance mechanism for units opting to demonstrate that their gaseous fuels meet the specification.

Small boilers often exhaust to small diameter stacks that do not have any test ports or test platforms installed. Similarly, based on the public comments received limited use units often do not have test ports or test platforms installed. For these units, we estimated the additional costs to these costs to construct or rent scaffolding and install test ports. The costs include installation of 4 test ports, 90 degrees opposed to each other, and five weeks rental of temporary scaffolding. EPA estimates that these small sources would incur an additional $196 million to install test ports and rent temporary scaffolding. Many establishments in each industry, commercial, or institutional sector are associated with multiple (as many as a 700) small units. A summary of the costs by fuel category is shown in Table 3-1 below.

Table 3-1: Cost Estimate for Renting Scaffolding and Constructing Test Ports at Limited Use and Small Boilers and Process Heaters

Fuel Category	Number of Limited Use and Small Boilers and Process Heaters	Port Costs ($2008)	Renting Temporary Scaffolding ($2008)	Total Costs ($2008)
Coal	15	164,722	210,000	374,722
Biomass	21	230,610	294,000	524,610
Gas 1	7433	81,624,999	104,062,000	185,686,999
Gas 2	51	560,053	714,000	1,274,053
Liquid	358	3,931,353	5,012,000	8,943,353
Total	7,878	86,511,737	110,292,000	196,803,737

Monitoring Costs

Various monitor configurations were installed based on the size of the unit and the pollution control devices expected to be installed to achieve the MACT floor emission limits. For units expected to install packed bed wet scrubbers, an annualized cost of $5,600 for a scrubber parametric monitor was included in the cost analysis. If a unit was expected to install DIFF, the cost to monitor sorbent injection rate and add a bag leak detection monitor was included in the analysis, based on the unit's hours of operation. For units expected to install a fabric filter, an annualized cost of $9,700 for a bag leak detection monitor was included in the cost analysis. If a unit was expected to install ACI, the cost to monitor the carbon injection rate was included in the analysis, based on the unit's hours of operation. For units that did not install a PM CEMS and did not install a scrubber to meet HCl limits, an annualized cost of $14,660 for an opacity monitor was included in the cost analysis. While the final rule includes a cutoff of greater than 250 mmBtu/hr, in order to be consistent with the thresholds in the boiler NSPS (40 CFR 60, Subparts Db and Dc) the cost analysis includes the cost of a PM CEMS for units with a heat input capacity of 250 mmBtu/hr or more. Oxygen monitors were required for all boilers and process heaters subject to CO emission limits, these monitors were assumed to be extractive type monitors with an annualized cost of $1,436. Although several units are expected to have O2 monitors installed on the units for other reasons, such as to monitor combustion efficiency, since the number of units with monitors installed and calibrated according to EPA performance specifications is unknown, this analysis applies the cost of an O2 monitor to all units subject to a CO emission limit. No PM CEMS or opacity monitors were assumed for boilers and process heaters designed to gaseous fuels.

Fuel Savings Impacts

This cost analysis includes an estimate of energy savings of one percent for every unit that is expected to install controls to improve combustion, or conduct an annual tune-up or energy audit. Further, documents from the Sustainable Energy Authority of Ireland have charted efficiency gains as a function of boiler fuel type and time elapsed since the previous tune-up.[8] Many best practices are considered pollution prevention because they reduce the amount of fuel combusted which results in a corresponding reduction in emissions from the fuel combustion. Further boiler tune-ups have been shown to improve the efficiency of a boiler between 1 and 5 percent, depending on the age of the unit and the time lapse since the previous tune-up[10-15, 17-19]. Other combustion controls such as upgrading burners and installation of an LBMS are also expected to improve the efficiency of the unit, thus reducing fuel consumption. This cost analysis assumes an annual fuel savings of 1 percent. The energy savings is estimated using the Equation 3:

Annual Fuel Savings (mmBtu/yr) = DC * CF * Op_{hours}* EG **(Equation 3)**
Where:
DC = unit design capacity (mmBtu/hr)
CF = capacity factor, 90% of design capacity
Op_{hours} = annual operating hours reported in 2008 survey (hours/year)
EG = Efficiency gain, estimated to be 1%

After the fuel savings for each boiler and process heater was calculated, the both industrial and commercial prices for coal, #2 distillate fuel oil, #6 residual fuel oil, and natural gas were obtain from the EIA.[5] The EIA data reported fuel prices as $/ton for coal, $/thousand cubic feet for natural gas, and cents per gallon for fuel oil. The higher heating values were obtained from Table C-1 of the EPA Mandatory Reporting Rule (40 CFR part 98 subpart C) and the higher heating values were used to convert the fuel prices to a standard unit of measure, $ per mmBtu. Using the NAICS code reported by each facility and the fuel category assigned to each combustion unit, the appropriate fuel price was multiplied by the calculated fuel savings. Table 3-2 below shows the distribution of reported NAICS codes considered as industrial versus commercial in terms of fuel pricing.

Table 3-2: Summary of NAICS Code Distribution by Sector

Sector	NAICS Codes
Industrial	221, 311, 312, 313, 314, 316, 321, 322, 323, 324, 325, 326, 327, 331, 332, 333, 334, 335, 336, 337, & 339
Commercial	111, 113, 115, 211, 212, 423, 424, 441, 481, 482, 486, 488, 493, 531, 541, 561, 562, 611, 622, 623, 811, 921, & 928

This cost analysis only estimates the fuel savings from units in the coal, liquid and natural gas and other gaseous fuel categories. A fuel savings was not estimated for units in the biomass fuel category since the price of biomass fuels is variable, and often biomass is an on-site industrial byproduct instead of a purchased fuel. The logic behind the costs analysis for new units were identical to that of existing units for the recommended option with the exception of the energy audit. Energy audits are a recommended beyond-the-floor option for existing units only and therefore no costs for an audit were included in the new source floor analysis.

3.2 Alternative Option

The alternative option includes control device and testing/monitoring cost estimation logic identical to the Recommended Option outlined above, except that units combusting biomass and coal must meet separate numeric emission limitations for Hg, PM, and HCl. All other aspects of the options are identical. As a result of this modified option and its computed MACT floors, the number of solid fuel units estimated to install controls to meet the limits were adjusted as follows:

- A new fabric filter was estimated to be installed at 451 existing boilers and process heaters to control Hg emissions. This does not include the fabric filters installed in combination with dry injection to achieve HCl control. A new fabric filter is required to be installed on 3 fewer boilers and process heaters under this option when compared to the recommended option.
- Incremental ACI equipment was estimated to be installed at 11 existing boilers and process heaters for the controlling Hg. Incremental ACI equipment is required to be installed on 97 fewer boilers and process heaters compared to the recommended option.
- ESP technology was estimated to be installed at 34 existing boilers and process heaters to control PM. ESP technology is required to be installed on an additional 24 boilers and process heaters under this option when compared to the recommended option.
- Wet scrubbers were estimated to be necessary to control HCl emissions at 774 existing boilers and process heaters. This is identical to the number of sources estimated to install a scrubber for HCl control under the recommended option.
- DIFF was identified to be necessary to control HCl emissions at 390 existing boilers and process heaters. DIFF is estimated to be installed on an additional 254 boilers and process heaters under this option when compared to the recommended option.
- Incremental sorbent injection was identified to be necessary to control HCl emissions at 23 existing boilers and process heaters. Incremental sorbent injection is estimated to be installed on an additional 16 boilers and process heaters under this option compared to the recommended option.

3.3 New Unit Options

The recommended option for new units follows the same logic for estimating control costs as the recommended option for existing units outlined above with one exception. For boilers with a rated heat capacity less than 500,000 Btu per hour, a tune-up cost of $200 was selected. This value was based on research of tune-up costs for similarly sized home boiler programs, which suggested the costs of a tune-up ranged from $60 to $150.[19,20] The alternative option for new units is also identical to the alternative option for existing units. However, no new boilers or process heaters combusting solid fuels are expected to be constructed by 2013. Since the differences in the recommended and alternative options are focused only on boilers and process heaters combusting solid fuel, there are no differences in the recommended and alternative options for new units. The new unit analysis also projects new gaseous fuels, but based on the EIA data used for the new unit projections all of these new boilers are estimated to be natural gas so no cost for a gas specification is included in the new unit analysis.

3.4 Summary of Cost Impacts

The recommended option is the promulgated option for existing and new boilers and process heaters. Tables 3-3 and 3-4 summarize the costs of the promulgated option for new and existing units. Appendix A of this memorandum provides a detailed summary of the costs according to unit size, subcategory, and individual control device costs. Appendix A also includes a summary of the costs on existing units under the alternative option considered in development of the final rule.

Table 3-3: Summary of Costs of Promulgated Options
Costs shown in $\$10^6$ (2008) with capital recovery estimated at 7%

Type of Unit	Option	Number of Units	TAC	TAC considering fuel savings	Testing & Monitoring TAC	Control TAC	Control TCI
New	Recommended	47	$6.3	$6.1	$0.3	$5.9	$20.9
Existing	Recommended	13,840	$1,804	$1,376	$135	$1,669	$5,082

Table 3-4: Summary of Total Annual Costs by Control Type for Existing Units under Recommended Option
Costs shown in $\$10^6$ (2008) with capital recovery estimated at 7%

Number of Boilers	Fabric Filter	ESP	Wet Scrubber	DIFF	Increased Caustic Rate	Combustion Controls and Oxidation Catalysts	Activated Carbon Injection	Work Practices (Tune-up)	Energy Audit
13,840	391	3.5	578	423	2.0	219	17.5	35.1	26.5

4.0 METHODOLOGY FOR ESTIMATING EMISSION REDUCTIONS

This section discusses the methodology used to estimate emission reductions from boilers and process heaters at both existing and new facilities and it presents a summary of the results for the recommended regulatory options.

4.1 Emission Reductions from Existing Boilers and Process Heaters

The emission reductions analysis for existing combustion units was done for each boiler and process heater in the major source inventory. There are a total of 13,840 boilers and process heaters at major sources that reported data in the 2008 questionnaire (ICR No. 2286.01). Each combustion unit was assigned a unit-specific or average baseline emission factor, depending on the availability of emission data reported for the unit. A detailed discussion of the procedures and results of the baseline emissions analysis is presented in another memorandum.[6]

Emission Reductions for Recommended Option

Emission reductions for PM, HCl, Hg, CO, and dioxins/furans were calculated on a ton per year basis by subtracting the baseline emissions assigned to each unit from the MACT floor emission limits corresponding to each unit's subcategory. A detailed discussion of the procedures and results of the MACT floor analysis is presented in another memorandum.[1] A percent reduction was calculated for CO. It was assumed that each combustion unit would achieve an identical percent reduction from baseline emissions for THC and VOC as was achieved for CO. A percent reduction was also calculated for HCl. It was assumed that each combustion unit would achieve an identical percent reduction from baseline emissions for HF as was achieved for HCl. A combustion unit is assumed to install a scrubber or DIFF for HCl control if it is not currently meeting the HCl floor limit, and if it doesn't already have a scrubber installed. For units required to install a scrubber or DIFF, it was assumed that the control will achieve a reduction from baseline for SO2 equivalent to the reduction in HCl. The logic for estimating SO2 reductions is a change since the proposal of the rule, to address public comments concerned with overestimating SO2 reductions. At proposal we had estimated that all units installing control for HCl removal would achieve a 95 percent reduction in SO2; by reducing the removal efficiency for SO2 to be equivalent to the reduction efficiency for HCl the revised emission reductions are more in line with the capability of the control devices estimated to be installed. A percent reduction in PM was also calculated in order to estimate total non-Hg metals reductions. It was assumed that each combustion unit would achieve an identical percent reduction from baseline emissions for each non-Hg metallic HAP as was achieved for PM. PM2.5 emissions were assumed to be a fraction of total filterable PM emissions based on fuel and control device configuration installed on the unit. The methods used to derive the contribution of PM2.5 to overall filterable PM are presented in other memoranda.[4] To calculate emission reductions for PM2.5, the emission reductions for PM were multiplied by the applicable PM2.5 fraction. Emission reductions for all pollutants for which there was no floor value were calculated on a ton per year basis.

To convert emission reductions from an emission rate on a heat input basis to an annual emission rate, Equation 4 was used:

$$\text{Annual Emission Rate (tpy)} = ER_{HI} * 0.0005 * Op_{hours} \qquad \textbf{(Equation 4)}$$

Where:
ER_{HI} = emission rate (lb/mmBtu)
0.0005 = conversion factor, lbs per ton
Op_{hours} = annual operating hours reported in 2008 survey (hours/year)

To convert emission reductions from a concentration basis to an annual emission rate, Equations 5 and 6 were used:

$$\text{Annual Emission Rate (tpy)} = ER_C * 0.000001 * Q_S * 60 * Op_{hours} * MW * 0.0026 * 0.0005 * (20.946 - O_2) / (20.946 - \text{Std } O_2) \qquad \textbf{(Equation 5)}$$

Where:
ER_C = emission concentration (ppm @ 3% O_2)
0.000001 = conversion factor, ppm to parts
Q_S = exhaust flowrate (dscfm)
60 = conversion factor, minutes to hours
Op_{hours} = annual operating hours reported in 2008 survey (hours/year)
MW = molecular weight of pollutant, in lb per lb-mole
0.0026 = conversion factor, lb-mole per dry standard cubic foot of gas
0.0005 = conversion factor, lb per ton
20.946 = percentage of oxygen in ambient air
O_2 = percentage of oxygen assumed in exhaust gas
Std. O_2 = 3 percent oxygen in standardized emission concentration for promulgated rule.

Annual Emission Rate (tpy) = $ER_C * 0.0283 * Q_S * 60 * Op_{hours} * 0.000000001 * 0.0022 * 0.0005 * (20.946 - O_2) / (20.946 - Std\ O_2)$ **(Equation 6)**

Where:

ER_C = emission concentration (ng/dscm @ 7% O_2)

0.0283 = conversion factor, dry standard cubic meter per dry std. cubic foot

Q_S = exhaust flowrate (dscfm)

60 = conversion factor, minutes per hour

Op_{hours} = annual operating hours reported in 2008 survey (hours/year)

0.000000001 = conversion factor, ng to g

0.0022 = conversion factor, g per lb

0.0005 = conversion factor, lb per ton

20.946 = percentage of oxygen in ambient air

O_2 = percentage of oxygen assumed in exhaust gas

Std O_2 = 7 percent oxygen in standardized emission concentration for promulgated rule.

Converting concentrations to an annual emission rate required an oxygen concentration and exhaust flowrate estimated for each specific fuel type. The development of these assumptions and estimates is presented in other memoranda.[2] All conversions required the annual operating hours for each combustion unit reported in the 2008 survey. If no operating hours were reported, the unit was assumed to operate for 8,400 hours per year (two weeks of downtime).

For units not subject to emission limitations, the emission reductions were based on a one percent gain in efficiency expected from the annual tune-up work practice standard. Efficiency gains reduce fuel use, and in turn, emissions of hazardous air pollutants. A one percent reduction in all types of emissions was estimated by multiplying the baseline emissions for each unit by a factor of 0.01.

Emission Reductions for Alternative Option

The same calculations discussed for estimating emission reductions for the recommended option were applied to all units except that boilers and process heaters combusting biomass and coal were subject to separate numeric emission limits for Hg, PM, and HCl. In these cases the adjusted MACT floors under this alternative option were subtracted from baseline emissions and then the remainder of the above calculations for the recommended option was performed.

4.2 Emission Reductions from New Boilers and Process Heaters

Based on industrial and commercial fuel consumption projections from the EIA, there are 47 new boilers and process heaters expected to come on-line by 2013.[5] a discussion of the methodology used to project new boilers and process heaters is discussed in another memorandum.[3]

The New Source Performance Standards for Industrial, Commercial and Institutional Boilers (40 CFR part 60, subparts Db, Dc) (NSPS), was reviewed to identify the expected baseline level of control for projected new units. It was determined that new boilers and process heaters larger than 30 mmBtu/hr and combusting biomass would install an ESP. This technology selection is based on the analysis used to establish the PM NSPS limit for biomass boilers. New coal units larger than 75 mmBtu/hr would have a fabric filter and wet scrubber installed, while new coal units between 30 and 75 mmBtu/hr would only have a fabric filter installed and would meet the SO_2 limits in the NSPS by using coals with low sulfur content. New units larger than 30 mmBtu/hr and combusting liquid fuel would have a fabric filter installed. All new units less than 30 mmBtu/hr would have no add-on controls and liquid fuels were expected to meet the NSPS SO_2 limits using low sulfur fuel oils. Gas-fired units of all sizes were not expected to install controls to meet any of the NSPS limits. For this impacts analysis, it was assumed that all new solid fuel units would be stokers, since stoker boilers are the most common type of solid fuel boilers and all new units would have NOx control installed as a baseline control, regardless of fuel.

After an appropriate baseline level of control was determined for each model unit, an average baseline emission factor calculated for existing units within the same fuel category and having the same level of control was assigned to each model boiler. The NSPS specifies PM and SO2 limits for new solid- and liquid-fired combustion units based on heat input. It was assumed that all new solid and liquid units would be constructed to meet these limits, so they were used as baseline emission values where applicable. The baseline emissions for each unit were subtracted from the new source MACT floor emission limit corresponding to each unit's subcategory. The same calculations discussed in Section 3.1 of this memo were used to estimate the reductions for new units.

Similar to the methods discussed in Section 4.1 of this memorandum, the emission reductions for new units were calculated by subtracting the baseline emissions assigned to each unit from the MACT floor emission limits corresponding to each unit's subcategory, except for units not subject to numeric emission limits. For units not subject to emission limitations, the emission reductions were based on a one percent gain in efficiency expected from the tune-up work practice standard. A summary of the estimated emission reductions at existing units for both the recommended and alternative options are located in Appendix B-1.

5.0 METHODOLOGY FOR ESTIMATING SECONDARY IMPACTS

Secondary impacts include the solid waste, water, wastewater, electricity required to operate air pollution control devices and the resultant greenhouse gas emissions, as well as the additional energy savings resulting from improved combustion controls or work practices required by the NESHAP. This section documents the inputs and equations used to estimate these secondary impacts, and it summarizes the impacts at existing units under promulgated regulatory option 4 and new units under promulgated regulatory option 1. Table 5-1 summarizes the cost, emission, and secondary impacts of this promulgated NESHAP. Appendices C-1 and C-2 present a detailed breakdown of the secondary waste, water, and energy impacts from each subcategory of new and existing boilers and process heaters, respectively.

Table 5-1: Summary of Secondary Impacts

Impact	New Units (recommended option)	Existing Units (recommended option)
Water (gal/yr)	242,000	671 million
Wastewater (gal/yr)	193,900	266 million
Solid Waste (tons/yr)	580	100,500
Purchased Electricity (kW-hr/yr)	6.2 million	1.4 billion
CO2 Emissions from Purchased Electricity (tons/yr)	4,100	910,000
Energy Savings* (trillion Btu/yr)	0.01	44.5

* Energy savings is calculated for units in the coal, liquid and gas subcategories.

The secondary impacts were calculated using algorithms and assumptions described in another memorandum.[2] These algorithms and assumptions were applied to the existing boiler and process heaters, where the baseline emissions for each unit exceeded the promulgated MACT floor emission limit except for small units (less than 10 mmBtu/hr), limited use units, and units firing natural gas, refinery gas, or other on-spec gaseous fuels. A one percent energy savings was calculated for all units, including the small, limited use and gas-fired units since these units are expected to conduct a tune-up. For new units, the algorithms and assumptions were applied to model units representing units expected to come online between 2010 and 2013, when the baseline emissions for each model exceeded the promulgated MACT floor emission limit for new units except for small units and units firing natural gas, refinery gas, or other on-spec gaseous fuels. Similar to existing units these small and gas-fired units are not required to meet a numerical emission limit, and therefore not expected to incur any secondary waste, water, or electricity impacts from these controls. A one percent energy savings from small units and units burning natural gas, refinery gas, or other on-spec gaseous fuels are included in the energy savings estimate in Table 5-1 since these units are expected to conduct a tune-up. The methodology used to assign baseline emission factors to new and existing units are discussed in another memorandum.[6]

5.1 Wastewater and Water Impacts

The water required to create a slurry in the packed scrubber and the wastewater generated by the effluent of a packed bed scrubber were calculated for every unit expected to install a scrubber to meet the HCl limits in the promulgated rule. Both the water and wastewater calculations required the use of several constants and variables. The constants including the density of gas, moles of salt needed per mole of hydrogen chloride in the exhaust gas, the molecular weight of the salt used, the fraction of the waste stream treated, operating hours per year and the molecular weight of the gas. The data sources for these constants are provided in another memorandum.[2] The variables used to estimate the quantity of water required and wastewater generated were calculated based on characteristics reported for each existing unit in the 2008 survey and for the characteristics assigned to each new model unit. The variables included: exhaust flow rate from the combustion unit to the control device in actual cubic feet per minute, the inlet loading of hydrogen chloride to the control device (mole fraction), and the efficiency of the control device in removing hydrogen chloride from the exhaust gas (percent reduction). The calculations used to estimate each variable are provided in another memorandum.[2] The total national water and wastewater amounts in Table 5-1 were determined by adding the per unit water and wastewater estimates for all new and existing units, respectively.

5.2 Solid Waste Impacts

Solid waste is generated from collecting dust and fly ash in fabric filters or ESP control devices, spent carbon associated with ACI, or spent caustic from increasing the caustic injection rate. Solid waste impacts were estimated for every unit expected to install a fabric filter for mercury control or a DIFF for HCl control, ACI for mercury emission limits, or install an ESP to meet PM emission limits. The total national solid waste amounts in Table 5-1 were determined by adding the per unit solid waste estimates for all new and existing units, respectively. To estimate the solid waste contribution from each of these control devices, the variables were calculated based on characteristics reported for each existing unit in the 2008 survey and for the characteristics assigned to each new model unit. The calculations used to estimate each variable and the quantity of solid waste generated are provided in another memorandum.[2]

The solid waste (dust, fly ash) generated by the use of an electrostatic precipitator was calculated when an electrostatic precipitator was determined to be necessary to meet the NESHAP emission limits for PM. Estimates of the solid waste collected in an ESP was based on several variables including: exhaust flow rate from the combustion unit to the control device (acfm); the inlet loading of particulate matter to the control device (gr/acfm); operating hours (hr/year) and the efficiency of the control device required to meet the PM emission limits in the promulgated NESHAP.

The solid waste generated from the collection of dust and fly ash in a fabric filter was calculated when a fabric filter was determined to be necessary to meet the promulgated NESHAP emission limits for particulate matter and/or mercury. The calculation required the use of three variables, including: exhaust flow rate from the combustion unit to the control device (dscfm); operating hours (hr/year) and the inlet loading of particulate matter to the control device (gr/acfm).

For this analysis, the spent carbon collected from units with ACI is assumed to be disposed of instead of being re-generated. The amount of spent carbon created from ACI was calculated when ACI was expected to be necessary to meet the promulgated NESHAP emission limits for mercury or dioxin/furan. The calculation required the use of six variables, including: exhaust flow rate from the combustion unit to the control device (dscfm); operating hours (hr/year), required removal efficiency for mercury and dioxin/furan, and an adjustment factor based required removal efficiency of mercury or dioxin /furan.

The solid waste generated by the use of increased caustic was calculated for those units where additional caustic was expected to achieve the promulgated NESHAP emission limits for HCl. The calculation required the use of three variables, including: exhaust flow rate from the combustion unit to the control device (dscfm); operating hours (hr/year), and the required removal efficiency for HCl.

5.3 Electricity Impacts

The amount of electricity required to operate a control device was calculated for a packed scrubber, electrostatic precipitator, fabric filter, DIFF, CO oxidation catalyst and the fans for the ductwork associated with this equipment. These impacts were assessed for every unit that was estimated to require hydrogen chloride and/or particulate matter control. Electricity requirements are one output of the cost algorithms used in the analyses, so no additional calculations were necessary. For some units, an electrical demand from multiple control devices was estimated. The total national electricity demand in Table 5-1 was determined by adding the per unit solid waste estimates for all new and existing units, respectively. To estimate the electricity demand from each of these control devices, a set of variables were calculated based on characteristics reported for each existing unit in the 2008 survey and for the characteristics assigned to each new model unit. The constants, variables, and calculations used to estimate each variable and the electricity demand to operate the control devices are provided in another memorandum.[2]

5.4 Greenhouse Gas Emissions from Electricity Usage

Since greenhouse gases are generated from electricity production, an estimate of carbon dioxide emissions was generated for the electricity impacts of the add-on air pollution control devices. The total electricity usage from all control devices was multiplied by the national average carbon dioxide emission factor for carbon dioxide emissions from EPA's 2005 e-GRID to obtain the expected annual carbon dioxide emissions.[9] No carbon dioxide emissions were estimated for boilers or process heaters conducting a boiler tune-up since no electricity impacts were estimated for those units.

5.5 Energy Savings Impacts

The energy savings from combustion controls such as low NOx burners or linkageless boiler management systems, and work practice standards, including a tune-up, and implementing the energy audit findings with a short-term payback can improvements in efficiency, thereby reducing fuel consumption. This secondary impacts analysis only estimates a one percent efficiency gain from tune-up work practices and installation of combustion controls to be conservative and consistent with the assumptions made in Section 3.1 of this memorandum. No energy savings are attributed to the energy assessment in this analysis. Quantifying the exact gains in efficiency from each of these work practice standards is difficult, and may depend on the baseline operating efficiency of each unit.

Section 3.1 discusses the fuel savings impacts in terms of annualized cost savings to each boiler or process heater, and the national energy savings presented in Table 4.1 of this section follows the same methodology as was discussed in Section 3.1 and reflect the savings from boilers in the coal, gas, and liquid fuel categories only.

5.6 Estimating Secondary Impacts for Existing and New Units

Appendices C-1 and C-2 present a detailed breakdown of the secondary waste, water, and energy impacts from each subcategory of new and existing boilers and process heaters, respectively. The differences presented between the recommended and alternative regulatory options are based on the number of controls estimated to be installed to meet the floor limits associated with each option, which in turn affects the amount of waste, wastewater, water, and energy consumed by the control devices installed for PM, HCl, and Hg.

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